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Cost Benefit Analysis of Wind Turbine Investment in Oberlin, Ohio

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Cost Benefit Analysis of Wind Turbine Investment in Oberlin, Ohio

Introduction

As concern over global climate change and fears of rising energy costs permeate our collective and individual decision making, more and more private institutions are seeking out innovative and feasible solutions to meet these issues. Many colleges and universities throughout the United States have been among the first private and public institutions to dedicate themselves to positions of climate neutrality and have begun to incorporate the ethics of conservation and commitment to environmental sustainability into their primary objectives. To date nearly five hundred institutions of higher education have signed the American College and Universities Climate Change Commitment, pledging to take immediate and prolonged action to reduce their foot print of carbon dioxide and other greenhouse gas emissions.¹ Undoubtedly many of these schools will be able to implement extensive and inexpensive improvements in the efficiency of current facilities and practices in order to meet their objectives. However for those that have committed to complete climate neutrality, such as Oberlin College, additional measures extending beyond the traditional endeavors of an educational institution may also become necessary. One such option that has received attention from the Oberlin community is the construction of a utility scale wind turbine.

Although there are many other alternatives that the College may investigate, the choice to be considered here is between investing in a wind turbine or purchasing carbon offsets commercially. Naturally the college faces tradeoffs as it allocates its budget between turbines,

¹ <http://www.presidentsclimatecommitment.org/>

offsets, and its myriad other operational activities, so a cost benefit analysis is particularly useful in comparing the advantages and disadvantages of investment in various turbine models. This paper addresses several primary objectives. First, the analysis conducted here will update previous research on the topic of the viability of wind power in Oberlin by incorporating spot market electricity prices into the calculations of net benefits and by utilizing a more conservative model of the cost schedule. This paper will also address many of the economic issues inherent in the college's desire to minimize expenditures while decreasing its footprint assuming that it will choose the option with the least cost per unit of emissions offset. Using a standard cost benefit analysis, and exploring the sensitivity of the results to a range of parameters, the results show that a wind turbine in Oberlin will under extremely conservative conditions reduce the carbon emissions footprint at a cost comparable to many commercially available carbon offsets, and that as these conditions are relaxed positive net present values emerge.

The rest of the paper will be organized as follows. The next section reviews relevant literature and focuses the motivation of this study. Section 3 is a statistical summary of the electricity price and wind speed data is presented. Following that a description of the procedures used in calculating generation, revenue, cost, and net present value figures is outlined. In section 4 the results are presented in the subsequent section, and discussion of their sensitivity to various parameters as well as various interpretations follow.

II. Literature Review

There is a great deal of recent scholarship that pertains to decision making about investments in alternative energy. The studies reviewed here investigate the impact of carbon taxes and permits on energy investment, increased deployment of renewable energy sources into existing electric systems, and the interaction between both of these trends in both traditional and

deregulated electricity systems. Much of this research focuses on patterns and projections of industry and nation wide energy prices and investment rates. There also exists considerable research on the value of real options theory in energy investment. Scholarship focusing on the influence of carbon prices shrouded by uncertainty on individual investors and operators is more limited. Real options approaches have been used in some cases to determine optimal timing and scale of investments in markets facing the specter of uncertain carbon prices at some point in the future. Work has also been done in a real options framework that combines the importance of the spot market in determining the value of an investment in generation given uncertainty in carbon prices. The following section provides a review of a set of recent studies that have important implications for the design of the research undertaken in this paper, as well as the previous work addressing the viability of wind power in Oberlin.

Reedman, Graham, and Coombes (2006) use real options to determine the timing of an investment when prices are expected to follow an exogenously forecasted path and a carbon tax is expected to be implemented at an unknown level at some point in the future. The treatment of carbon price projections is simplified in order to highlight the large degree of uncertainty in both the timing and magnitude of a potential carbon tax. Five technology choices are considered, each of which vary in total output, sunk costs, and fuel costs, as well as the intensity of carbon dioxide emissions. A real options model is deployed under two circumstances, both of which include uncertainty as to the magnitude of the carbon tax (which is treated discretely), and one in which the timing of the tax's implementation is unknown and follows a simple distribution over a fixed horizon.

The most relevant aspect of Reedman, Graham, and Coombes (2006) for this paper is the treatment of uncertainty with regards to carbon prices in a real options framework for choosing

technologies that produce (or reduce relative to other possibilities) CO₂ emissions. CO₂ prices will play a critical role in Oberlin College's final decision, and may be considered one of the primary metrics in evaluating wind turbine utility. While the electricity price forecasting model described in their paper may have distinct advantages over others for capturing important nuances of the development of average or expected energy prices as pertains to national investment levels, this sort of approach is not necessary here as this paper deals with a specific investor in a specific area. One aspiration of this paper is to assess the importance of spot market electricity price variability in determining the viability of an intermittent generation source (such as wind), which is a topic that has not received adequate attention in the literature.

Hlouskova et al. (2005) focus on the challenge of unit commitment in deregulated power markets when the operator faces known costs and delays in starting up and shutting down, and uses an autoregressive model of spot market prices with identifier variables for day of the week and season as well as binomially distributed price spikes to forecast spot market prices in the short term. Their paper also contains a detailed characterization of the variability of spot market prices. Real options methodology is used to determine the optimal operating schedule of a generator with known "switching" costs and delays by establishing trigger prices for beginning and shutting down operations.

While switching is beyond the scope of this analysis, a careful consideration of the features of the spot market is essential. One of the chief goals of this paper is to highlight the importance of spot market variability in determining the value of wind power, and a detailed characterization of both electricity prices and potential wind generation data will be conducted in the following sections drawing largely on the format presented in Hlouskova et al. (2005). Their model of short term energy price forecasting may also be useful in assessing the potential for a

biogas co-generation facility which is one physical alternative also under consideration by Oberlin College, but is not covered explicitly in this study.

Although less common in literature describing industrialized countries, attempts have been made to describe the influence that the possibility of selling carbon offsets might have on the energy investment decisions of developing nations. One such study is presented in a chapter of the book Sustainable Energy in Developing Countries: Policy Analysis and Case Studies (2005) by Meier and Munasinghe. In their example, the forgone revenue from the sale of carbon offsets is included along with the cost of operating temporary generators in the cost of a delay in beginning an emissions reducing investment in large scale electricity generation capacity. Here the only options considered by the college are commercial offsets and offset from wind production, so the forgone expenditures on commercial offsets may be considered as benefits of producing and selling wind generated electricity. As in Reedman, Graham, and Coombes (2006) a simple probability distribution is deployed to represent uncertainty in the development of carbon prices.

The previous economic analysis of the viability of wind power in Oberlin conducted by Scofield et al. (2007) differs from that conducted here in several significant ways. The first is that Scofield et al. (2007) does not consider the revenue for selling the electricity on the grid, and instead compares a calculation of the average cost per kwh generated to the average retail price paid by end consumers and the average wholesale generation cost for OMLPS. The average cost per kwh generated is calculated with all capital costs averaged out over a 15 year project lifetime at a 5% discount rate. This paper will initially use the same project lifetime and discount rate, with the major differences being that all capital costs will be paid upfront, and revenue from the sale of electricity onto the spot market will be considered in the net benefits. Analysis will also

be presented that demonstrates the sensitivity of the results to changes in the lifespan and discount rate, as well as the cost structure.

One final aspect of the model to be presented here that has received some attention recently is the “quality” or risk associated with purchasing carbon offsets. While in simple terms the concept of a carbon offset seems sound, in practice their validity and efficacy may be questionable². One very thorough treatment of the current consumer market for carbon offsets is “A Consumer’s Guide to Retail Carbon Offset Providers” by Clean Air Cool Planet (December 2006). While this paper assumes a one to one tradeoff between emissions reduced through local wind power generation and those accounted for by offsets from an outside source, there is much in the literature that suggests that this may not be the case both in a physical and economic sense, as well as in how they are perceived. While a full dissection of the relative utilities of localized versus consumer offsets is outside the scope of this paper, the results could have a profound influence on the rate of investment in renewable energy and other physical small scale emissions reductions efforts. For the purposes of this paper however, uncertainty in the “quality” of a purchased offset can be considered a factor in increasing the risk of its price. The “quality” of an offset may be related to the reliability of the provider, or the additional benefits of the offset process (such as local job creation), and is subject to the concerns of the consumer. Carbon offsets that are highly rated by Clean Air Cool Planet (2006) for accountability and external benefits range in price from eight to twenty dollars, with a mean of fifteen dollars.

III Data Summary

Electricity Spot Prices

² “F.T.C. Asks if Carbon-Offset Money Is Well Spent,” Louise Story, New York Times, January 9th 2008, http://www.nytimes.com/2008/01/09/business/09offsets.html?_r=1&scp=2&sq=greenwashing+&st=nyt&oref=slogi
n

Figure 1. Geographic Footprint of the MISO



The electricity spot market pricing data used in this analysis comes from the Midwest Independent Service Operator (henceforth MISO), one of the largest deregulated energy markets worldwide covering an area of nearly one million square miles in the U.S. and Canada (see Figure 1). Monthly billing in the MISO totals nearly \$2.4 billion, and annual transmissions are approximately 655 Terawatt hours³ of electricity. The MISO was organized in 2001 as the first Regional Transmissions Operator in the United States, began transmission service (the management of the transfer of electricity between producers and consumers) in 2002, and initiated market services (generally the operation of bidding between buyers and sellers of electricity) in April 2005. The MISO coordinates a diverse mixture of generation sources, approximately one half of which are coal powered, over one quarter natural gas, seven percent nuclear, seven percent oil or oil and natural gas combination, four percent hydroelectric, slightly over two and a quarter percent from other sources, and one percent from wind energy sources.

The MISO conducts both day ahead and real time hourly spot markets in addition to a financial transmissions rights market, each of which is settled separately. Market participants submit bids consisting of both a quantity and a price per kilowatt hour for each hour of the day in both markets. Suppliers are selected in each market based on an algorithm that selects the lowest

³ A terawatt hour is one billion kilowatt hours. A kilowatt hour is a common measurement of energy, and is approximately the amount of energy a light bulb draws over an hour.

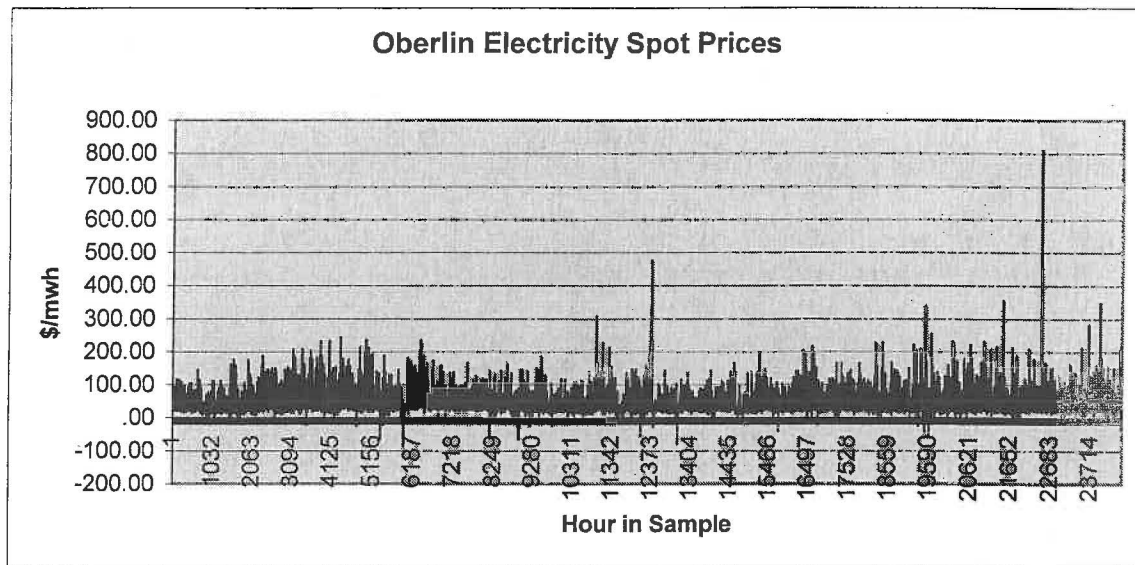
cost sources up to the point at which total demand is met, subject to congestion constraints on the grid. Due to the physical nature of electricity, it is more cost effective to allocate different prices to different regions, or nodes, both for buyers and suppliers of electricity. These localized prices include costs associated with generation, congestion, and physical loss due to transmission, and there are currently 1,765 nodes. Spot market prices are calculated every five minutes for the real time market (hourly for the day ahead), and historical average hourly prices are available online a few days after closing⁴.

Important exceptions in the market structure exist for generating sources whose ability to produce output is determined largely by fluctuations in natural environmental conditions, such as wind and solar. Such sources are referred to as intermittent generators. Typically, any supplier failing to produce their bid quantity of electricity in a given time period faces a penalty in the form of a fine, however all intermittent sources are exempt from this rule. Additionally, intermittent source generators are not permitted to enter bids in either the day ahead or real time markets and instead receive the market clearing price for each hourly (in the day ahead) or five minute increment (in the real time market) at their price node. The market clearing price is the highest price submitted by a generator whose capacity is necessary to fulfill demand requirements, and varies substantially throughout the day.

The data set consists of 24,552 hourly observations in the real time market from April 1st 2005 until January 19th 2008, and is plotted in Figure 2.

⁴ Data is available at www.midwestiso.org under the Market Info tab.

Figure 2. Locational Marginal Prices for the Node including Oberlin, Ohio

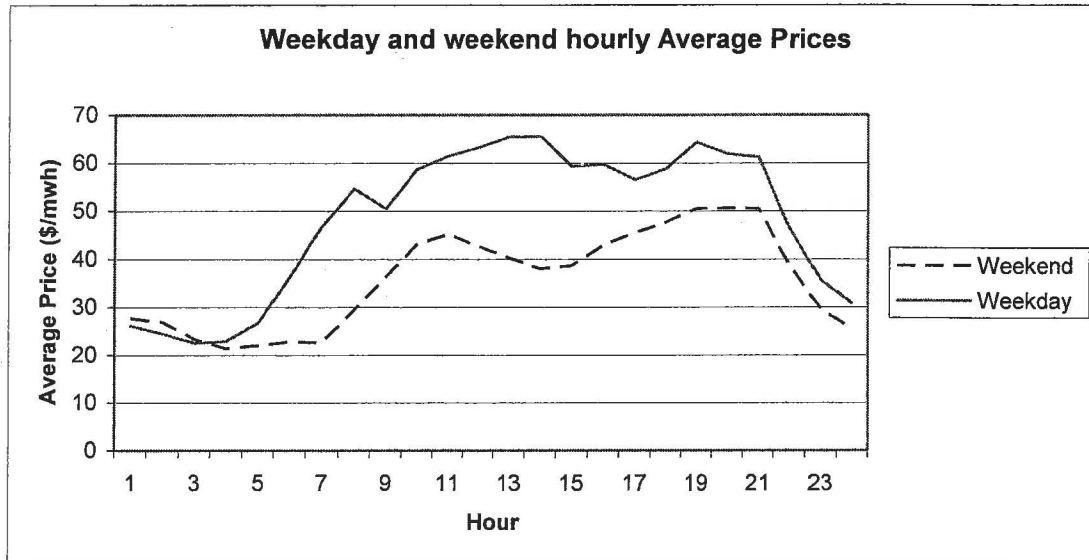


The mean price over this time period is approximately 44.83 dollars per megawatt hour, only slightly larger than one third of the average generating cost estimated in Scofield et al (2007). The maximum and minimum values in the set are \$809.30 and -\$78.49 respectively. There are relatively few extreme price spikes above 200 dollars per megawatt hour, and most spikes are extremely brief, lasting less than one or two hours. Negative prices are a relatively common, although somewhat counterintuitive, event in the MISO spot market, and represent instances in which demand temporarily falls far short of supply and operators are not willing to bear the cost of switching off.

The price data exhibit interesting qualities when weekday and weekend trends are compared. Typically one expects weekday average hourly prices to be consistently higher than weekend average hourly prices, and that trends within a twenty four hour cycle should be roughly consistent. The mean price of the weekdays (\$48.32) is higher than the mean of weekends (\$35.90), which confirms one of the two expectations listed above. However, trends in prices do not appear to be parallel in the two sets for much of the domain. Figure 3 illustrates

the mean price for each hour of the day for both weekdays and weekends (not accounting for holidays). It is interesting to note that for the hours between 12 AM and 3 AM the average price is actually higher for weekends than weekdays, and that trends in the weekend prices lag those in weekday prices by several hours.

Figure 3. Average Hourly Weekend and Weekday Spot Prices



Seasonal variation in prices also plays an important role in determining the value of a generating technology whose output is determined by the weather. Seasonal changes in pricing patterns are linked to a variety of factors, including temperature and seasonal economic conditions. Typically energy markets exhibit the highest prices in the hottest months, and the lowest in the most temperate. Figure 3 above plots the average price per hour for four seasons; Spring (March, April, and May), Summer (June, July, and August), Fall (September, October, and November), and Winter (December, January, and February).

Figure 4. Seasonal Average Prices by Time of Day

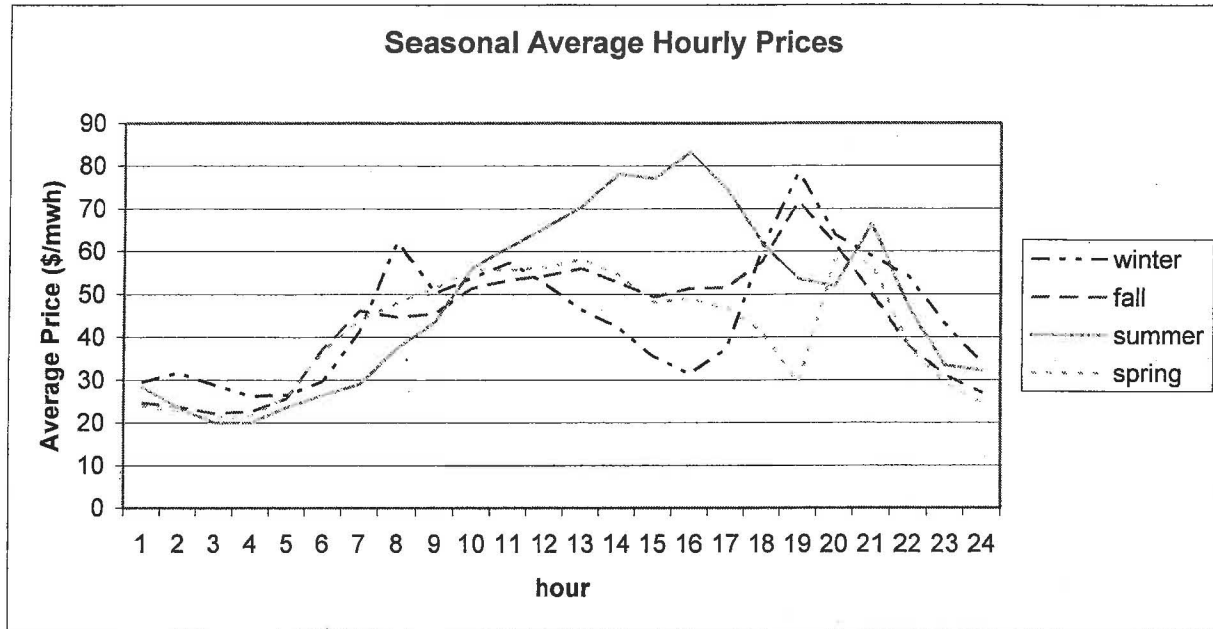


Table 1. Average Hourly Prices by Season

| | Winter | Fall | Summer | Spring |
|----------------------|--------|-------|--------|--------|
| Night (12AM-5AM) | 23.75 | 24.38 | 23.63 | 25.34 |
| Morning (6AM-11AM) | 52.84 | 49.21 | 48.8 | 51.81 |
| Afternoon (12PM-5PM) | 42.26 | 53.06 | 74.21 | 49.64 |
| Evening (6PM-11PM) | 55.31 | 46.56 | 47.38 | 39.27 |
| Night (12AM-5AM) | 23.75 | 24.38 | 23.63 | 25.34 |
| Morning (6AM-11AM) | 52.84 | 49.21 | 48.8 | 51.81 |
| Afternoon (12PM-5PM) | 42.26 | 53.06 | 74.21 | 49.64 |
| Evening (6PM-11PM) | 55.31 | 46.56 | 47.38 | 39.27 |

The data nominally confirm many of the generalizations described above. Summer has the highest mean (48.50) followed by Winter (44.77), Fall (43.70), and Spring (41.50). It may be important to note that the peaks for all seasons except summer occur between 7 and 9 o'clock PM, while the summer peak is during the late afternoon.

There also appears to be variations in the maximum and minimum average prices for a given set of hours across seasons, as well as in the extreme prices within a season across the time

of day. Table 1 above summarizes these results. In the top, red and blue signify the maximum and minimum average price for each set of hours across the seasons, and in the lower table red and blue are used to denote the extreme values within a season. It is important to note that for all seasons the lowest prices are in the Night period, when it is often the windiest. From these data it would appear that there are significant variations in price based on the season in which the observation occurs, and that when calculating expected benefits it is important to determine the correlation between wind speed and price at each specific time.

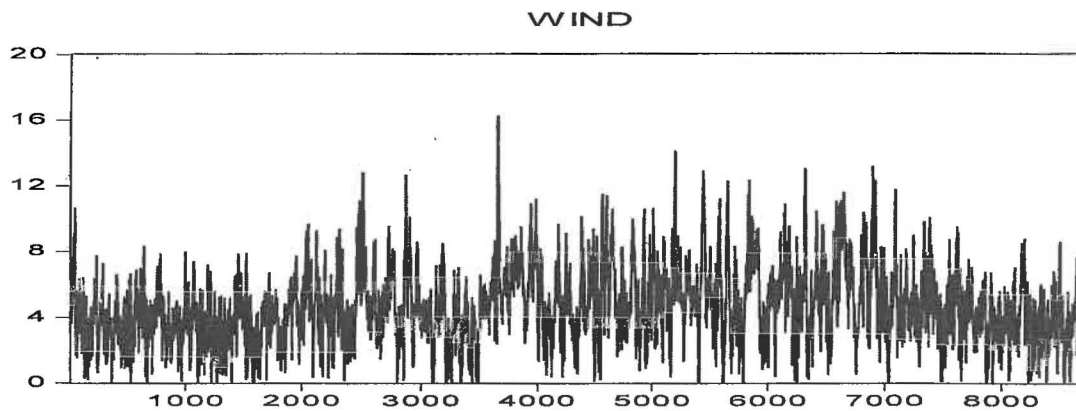
Wind data and Electricity generation

The wind speed data used in this study were collected by the Oberlin Wind Initiative. A thorough description of the process leading to and procedures undertaken by their data collection effort is presented in Scofield et al. (2007) and readers are directed to that study to gain the complete background of the project. The Oberlin Wind Initiative began as an offshoot of a class taught by Professor John Scofield in 2003. Funding for the monitoring station was provided by in part by Oberlin College, but also largely from the Oberlin City Council with the backing of Oberlin Municipal Power and Lights Systems which operates a small generation facility in town. This section will focus on describing the statistical features of the wind readings, and information on the extrapolation of wind speeds to different heights as well as the electricity generation estimation procedures will be provided later.

Wind measurements (in meters per second unless otherwise noted) were recorded every second (and subsequently averaged into one and ten minute intervals) at heights of 30, 40, and 50 meters along with directional, temperature, and pressure data by a monitoring site 3 miles to the north of Oberlin. The data to be used here cover one year beginning in July of 2006 through June of 2007 in ten minute increments. The data summary in this section will use the readings

from 50 meters, as wind speed varies with height, and we will be extrapolating from the data to infer estimates of wind speed at 80 meters, this gives us the closest measurement to the figures that will be used to calculate electricity production. The complete data set is provided in Figure 5.

Figure 5. Wind Speeds at 50m in m/s

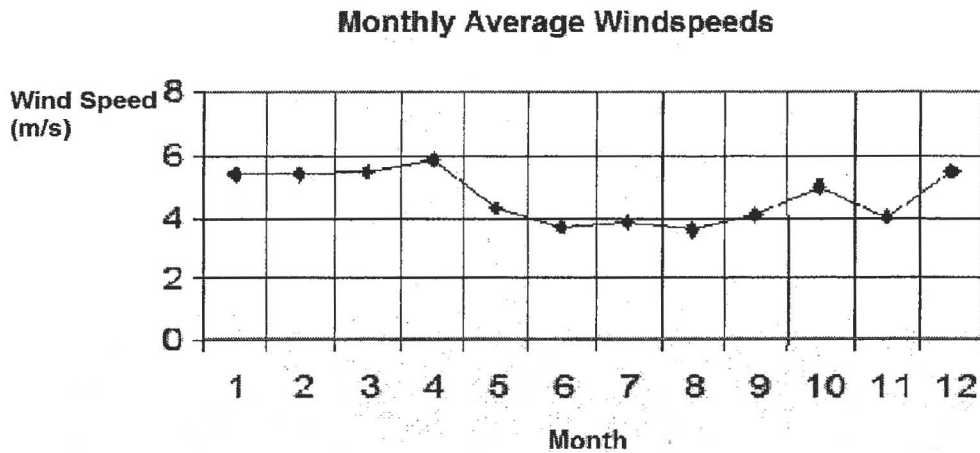


The mean speed over the entire time period is 4.633 m/s (10.36 miles per hour), and the maximum speed in the set is 16.203 m/s (36.25 miles per hour).⁵

Cyclical variation over a twenty four hour period as well as over months and seasons is, not surprisingly, visible in the data. As can be seen below in Figure 6, there seems to be a trend of high winds from January through April, slower average speeds from May through September, and then an increase again in October and December. The exception to this generalization appears to be November. Whether there exists a specific meteorological explanation to this feature, or if that particular November was especially calm is not clear.

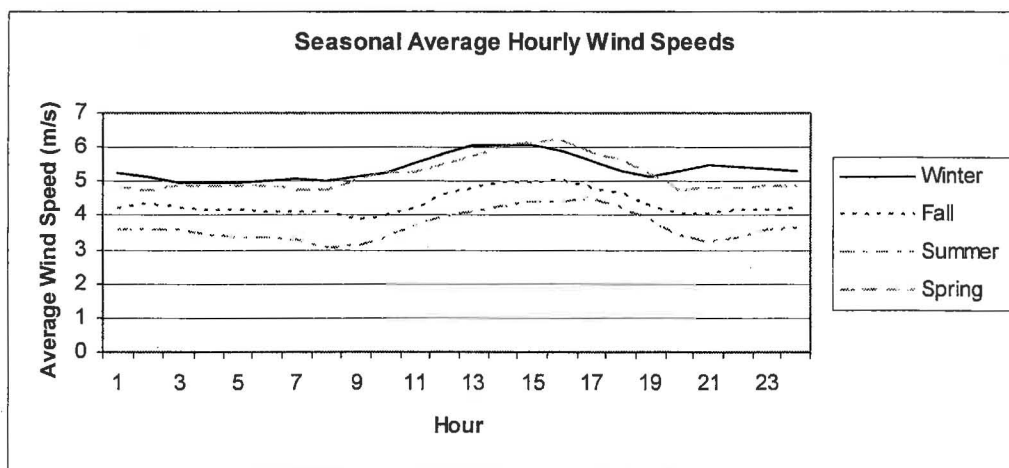
Figure 6. Average Wind Speeds by Month.

⁵ This figure of maximum wind speed may seem low to those familiar with Oberlin's typical weather patterns, so it is important to remember that the data used here are averaged over five minute increments. Wind speeds above 16.2m/s typically occur only in gusts, causing the five minute averages to be lower than the highest observed wind speed.



A clearer picture emerges when the average hourly wind speeds across the four seasons are compared (see figure 7. below). This picture illustrates that there are common features in the twenty four hour cyclical variation of wind speeds throughout the year. In each season a strong upward spike begins between 8 and 10 AM, peaks between 1 and 4 PM, and remains relatively constant throughout the remainder of the day. While the trends are common, it is clear that there exist significant differences in the levels of wind speed throughout the day across the seasons, with Winter on average the windiest, followed closely by Spring, and then Fall and Summer (recall that average energy prices by season in descending order are Summer, Winter, Fall, and Spring).

Figure 7. Average Hourly Wind Speeds by Month



Perhaps the most important statistical property of the wind and energy data for the purposes of this analysis is their statistical correlation. Although the relationship between wind speed and electricity generation is not linear, a feature that will be explored in the next section, it is still illuminating to explore a few aspects of the relationship between wind speeds and energy prices. Table 2 below illustrates the correlation between the average hourly wind speed and spot prices for the four seasons as well as each month of the year across both complete data sets. Red is used to signify the top third of a category, while blue indicates the lower third. No one month contains relatively high levels of each prices, winds, and correlation, nor does any month exhibit both relatively high wind speeds as well as high prices (although wind speeds in February are very close to the top third.)

Table 2. Average Monthly Wind Speed and Energy Price Statistics

| | Correlation | Mean Wind | Mean Price |
|-----------|-------------|-----------|------------|
| January | 0.0509 | 5.3687 | 40.7791 |
| February | 0.0093 | 5.3533 | 48.3451 |
| March | 0.1603 | 5.4531 | 42.7736 |
| April | 0.06573 | 5.8181 | 44.2496 |
| May | -0.0162 | 4.2509 | 39.3923 |
| June | 0.0161 | 3.6567 | 40.2674 |
| July | -0.0496 | 3.8297 | 49.2425 |
| August | -0.0261 | 3.5489 | 56.2202 |
| September | -0.0231 | 4.0171 | 42.8362 |
| October | -0.04297 | 4.9842 | 47.5671 |
| November | 0.0431 | 3.9584 | 41.1426 |
| December | 0.0059 | 5.4283 | 45.5086 |

Model

Electricity Generation Estimates

The first stage of the model utilizes wind speed data in conjunction with a wind turbine production function to estimate electricity generation. Wind turbine power curves approximate the electricity produced by a turbine at any given wind speed, and all exhibit four important features: a cut on speed (below which no electricity is produced), a cut off speed (above which

no electricity is produced), a peak speed, and a strictly increasing non-linear segment in between the peak and the cut on. Points along the curves for each of the models to be considered are recorded, and a five degree polynomial is regressed for each according to the form:

$$(Eq. 1) \quad Y(x) = A_n x^n + A_{n-1} x^{n-1} + \dots + A_1 x, \quad n=5$$

Where Y is electricity generated and x is wind speed in meters per second.

These curves are entered into a spread sheet, and the data was filtered to adjust for the cut on and peak speed levels for each curve (no speeds were recorded in Oberlin that reached the cut off speed for any of the models). Due to the nature of the fit, some of the models exhibited negative values for speeds very close to the cut on value. For the sake of computational ease a constant and conservative figure of 5 kwh was entered for these negative values uniformly across all models. After calculating the ten minute energy production estimates hourly production values were compiled as the average over each hour.

Cost Structure

Site and model specific information such as cost of connection to the grid and any auxiliary operational equipment for each turbine model is not available. In its stead a simple unit of dollars per kilowatt hour of peak capacity is applied as suggested by Scofield et al. (2007).⁶ While this figure is a simplification of the complex reality of the capital and installation costs of electricity generation facilities, it does allow several useful characteristics to be inferred. First, it seems sensible that higher capacity turbines should be more costly simply because they are physically larger. Changes in the price per unit of capacity may also be interpreted as improvements in the efficiency, and a decline in this unit has been observed over the long run as

⁶ Unfortunately, this figure may not be entirely realistic, a feature also acknowledged in Scofield et al (2007). However, in the absence of more accurate capital and installation cost estimates, it will be used here to provide a more useful comparison of the results of this study to those in Scofield et al (2007), and will be subject to sensitivity analysis in later sections.

the technology has improved. Special attention to the sensitivity of the estimate used for the cost per kwh will be paid in the next section. The cost suggested in Scofield et al. (2007), and used as a baseline in this analysis, is given as \$1,500 per kwh. Operational and maintenance costs in Scofield et al. (2007) are taken from those paid by Bowling Green University at a flat rate of \$50,000 per turbine per year.

Emissions Reductions Estimates

As discussed earlier there is a certain degree of flexibility in the qualifications of the various commercial offsetting techniques and options. The calculation to be used here applies the average amount of CO₂ emitted per unit of energy consumed in Ohio to the total amount of electricity generated by a turbine. The EPA estimates this figure to be equal to 0.892 kilograms of carbon dioxide emitted per kilowatt hour of energy consumed⁷. This means that each kilowatt hour of electricity generated by a wind turbine would reduce the College's footprint by 0.892 kilograms of CO₂, if we assume that electricity consumption is independent of the type of generation.

Certification of carbon offsets depends principally on verifying that all sources of carbon emissions within the process are accounted for and that the reduction in emissions is only counted once and attributed to only one party. For purposes of simplicity it will be assumed here that the transportation, operation, and maintenance of the wind turbine will result in negligible carbon dioxide emissions. While Oberlin College is not necessarily the end consumer of the electricity produced by the turbine, the College may reasonably assume a carbon credit for the electricity produced, so long as no other party claims credit. While it is possible that the electricity generated by the turbine would not be used within Ohio, which would make the

⁷ <http://www.epa.gov/cleanenergy/egrid.htm>

0.892kgCO₂/kwh estimate less accurate, the small scale and congestion constraints on the system make this possibility also highly unlikely⁸.

Wind Speed Extrapolation

As anyone who has ever flown a kite (or operated a utility scale wind turbine) will know, wind speeds tend to be positively correlated with distance from the ground in a given location. This physical characteristic of wind speeds, known as wind shear, may be estimated by the following equation⁹,

$$(Eq. 2) \quad V_u = V_k(h_u/h_k)^a$$

Where V_u is the velocity of the wind at the height to which you wish to extrapolate, V_k is the velocity of the wind at a height you have recorded, h_u is the height to which you wish to extrapolate, h_k is the height at which your known speed was recorded, and a is the wind shear coefficient. While there exists a theoretical constant value for a , in reality this value may change due to the existence of surrounding objects and other environmental characteristics, and must be calculated for each specific site. The wind speed data set used here consists of measurements from 30, 40, and 50 meters, so there are three possible ways to calculate a using measured data from one height as the unknown speed and data from a second as the known speed.

For example, using 50m as the unknown height and 40m as the known height, we can solve accordingly:

⁸ There is some theoretical debate as to whether or not offsets of this type can be considered reliable. One principal objection is that if consumers know that their energy comes from cleaner sources, and if their consumption is elastic with regards to source, then they will begin to consume more electricity thus reducing the offsetting effects. However as this turbine is small, and the end users of its electricity will have no way of determining whether or not they are using its product or another source, it seems unlikely that the addition of a turbine in Oberlin will effect the overall consumption patterns in the MISO footprint. Another concern is that the addition of a small wind turbine will not necessarily result in any less electricity being produced at other locations, especially if larger producers bear significant costs to marginally reducing output. However as there is no aggregate accounting information readily available for the amount of electricity generated that is not dispatched this effect would be nearly impossible to consider here, and will be assumed to be negligible for the purposes of this study.

⁹ Scofield et al. (2007)

$$(Eq. 2) \quad a = \ln(V_{50}/V_{40})/\ln(50/40)$$

The three resulting values for a are 0.436 (when average speeds from 50m and 40m are used), 0.388 (when 50m and 30m are used) and 0.351 (when 40m and 30m are used). Using 50m and 40m an average increase in wind speeds from 50m of 22.7752 percent is extrapolated, when 50m and 30m are used an average increase in wind speeds of 20.0298 percent is extrapolated, and when 40m and 30m are used an average increase of 15.7149 percent is extrapolated. When all three measures of a are averaged then the extrapolation from 50m to 80m yields average wind speeds that are 20.23 percent higher than those measured at 50m. Hence it seems that in general a measure of wind speeds that is about twenty percent higher than those measured at 50m will yield reliable estimates for wind speeds at 80m.

Net Present Value and Other Calculations

The calculations of net present value presented in the following section are intended to be highly conservative, and are then relaxed in the sensitivity analysis. The cost in each year is taken \$50,000, except in the first year when the capital cost of the turbine must also be paid. A discount rate of 5% and 15 year lifespan are used following Scofield et al (2007). The selection of the discount rate in any cost benefit analysis is often a difficult task. The White House Office of Budget and Management gives the ten and twenty year real interest rates on treasury notes as 2.6 and 2.8 respectively¹⁰, while noting that the private rate of return in recent years has been about 7 percent on average¹¹. The five percent discount rate used here is intended to be more conservative than the 2.6 or 2.8 risk free rate of return, but less so than the average rate of return on private investment.

Results

¹⁰ http://www.whitehouse.gov/omb/circulars/a094/a94_appx-c.html

¹¹ http://www.env-econ.net/2005/08/discount_rates_.html

Summary statistics for the seven models¹² considered in the Oberlin Wind Initiative's report are presented below in Table 3. These figures were calculated using wind speeds twenty percent higher than those recorded at 50m. The longevity horizon of the project used here is 15 years (a conservative estimate used by Scofield et al. (2007)), and a discount rate of 5% (also the parameter used in Scofield et al. (2007)). Generation estimates were created for each ten minute interval, and averaged into hourly generation estimates. It is assumed here that all capital costs of the turbines will be paid upfront during the first year that the turbine is operated, and that after that only the operational costs must be paid. The potential subsidies available include \$0.01/kwh for the first five years of generation from the

Table 3. Summary Statistics from Speeds Extrapolated to 80m, with Five Percent Discount and Longevity of 15 Years.

| | (1)GE2.5xl | (2)MWT92/2.4 | (3)REPmm92 | (4)V80-1.80 | (5)V82-1.65 | (6)GE1.5xle | (7)GE1.5sle |
|------------------------------|------------|--------------|------------|-------------|-------------|-------------|-------------|
| Annual Statistics | 2500 | 2400 | 2000 | 1800 | 1650 | 1500 | 1500 |
| Output (kwh) | 4339550 | 3918631 | 4158877 | 2868929 | 3093265 | 3052412 | 2706076 |
| output/capacity | 1735 | 1632 | 2079 | 1593 | 1874 | 2034 | 1804 |
| tons CO2 offset | 3870 | 3495 | 3709 | 2559 | 2759 | 2722 | 2413 |
| % of foot print offset | 7.74 | 6.99 | 7.42 | 5.12 | 5.52 | 5.45 | 4.83 |
| Sales Revenue (\$) | 200179 | 180971 | 191445 | 132749 | 142011 | 140426 | 124906 |
| 1st 5 years total Rev. | 326026 | 294612 | 312053 | 215948 | 231715 | 228946 | 203382 |
| 6-15th years total Rev. | 282630 | 255425 | 270464 | 187259 | 20083 | 198422 | 176322 |
| year 1 cost | -3800000 | -3650000 | -3050000 | -2750000 | -2525000 | -2300000 | -2300000 |
| all other years cost | -50000 | -50000 | -50000 | -50000 | -50000 | -50000 | -50000 |
| Discounted Values | | | | | | | |
| Total Revenue | 2446993 | 2211328 | 2341894 | 1621028 | 1738766 | 1718147 | 1526534 |
| Revenue/kwh capacity | 978.7972 | 921.386667 | 1170.947 | 900.57111 | 1053.7976 | 1145.4313 | 1017.6893 |
| Total Cost | -3843401 | -3705786 | -3155328 | -2880098 | -2673676 | -2467254 | -2467254 |
| NPV | -1396407 | -1494457 | -813433 | -1259069 | -934909 | -749106 | -940719 |
| NPV/ton of CO2 | | | | | | | |
| Reduced | -24.05 | -28.5 | -14.62 | -32.8 | -22.59 | -18.34 | -25.98 |

¹² The turbine names refer to the manufacturer, peak capacity, and other features of the turbine model. The GE2.5xl, GE1.5xle, and GE1.5sle are all manufactured by General Electric, and have peak capacities of 2.5, and 1.5 megawatts respectively. The GE1.5xle and GE1.5sle have many of the same features, but differ in the slopes of the their power curves. MWT92/2.4 is produced by Mitsubishi, has a blade length of 92 meters, and a capacity of 2.4 megawatts. The REPmm92 is manufactured by RE Power systems, has a blade length of 92 meters and peak capacity of 2 megawatts. The V80-1.80 and V82-1.65 are produced by Vestas, have peak capacities of 1.8 and 1.65 megawatts respectively, and respective blade lengths of 80 and 82 meters.

A few of the results in this table are immediately surprising. While one typically expects that larger turbines will produce more electricity than smaller ones, the REPmm92 out produces the much larger MWT92/2.4, while both the V82-1.65 and the GE 1.5xle produce more electricity than the V80-1.80. This is most likely the case because each of these models has a relatively lower cut on speed as well as a lower peak speed. The REPmm92 has the highest output per capacity, followed closely by the GE1.5xle. It is interesting to note that the top three turbines in terms of revenue per capacity, output per capacity, net present value, and cost per CO2 reduced are the same and in the same order in each category: the REPmm92, the GE1.5xle, and the V82-1.65. All models produce a net present value per ton of CO2 reduced that is comparable to many commercial carbon offsets, and the REPmm92 and GE1.5xle produce offsets at a lower cost than two of the offsets noted as “top tier” by Clean Air Cool Planet (2006).

The results in the table above have important implications in addressing the primary research questions investigated in this paper: the contribution of a wind turbine in the effort to best achieve carbon neutrality. From the figure above it can be observed that the decision maker might face a trade off between the total amount of emissions reduced, the price per unit of those reductions, and the net present value of the model selected. No one turbine model in the table above captures all three of these factors. The GE2.5x1 reduces the largest amount of the college’s foot print¹³, but has the fourth highest cost per unit reduced, the highest total cost, and the second worst net present value. The REPmm92 has the lowest price per unit of CO2 reduced, but a lower net present value and higher total cost than the GE 1.5xle.

¹³ Currently estimated as roughly 50,000 tons of CO2 per year.

Given these choices it would seem that the ultimate decision would depend on a variety of factors, including the total amount of money the College is willing to pay for capital, installation, and operational expenses, their concern for their net expenses, and their relative utility from offset reductions produced locally versus purchased commercially. Given that the college has expressed an interest in reducing emissions through local physical projects, and that their budget is limited and theoretically focused primarily on education, it would seem that they would most likely choose an option that has the lowest cost per unit of CO₂, the highest percentage impact on their total foot print, and the lowest total cost. Given these considerations, it would seem that the REPmm92 and the GE1.5xle are the two best choices.

Ranking the relative merit of these two options depends on the relative degree to which the factors mentioned above effect the college's decision. The table below contains the ratios of net benefits, price per ton of CO₂ offset, and percent reduction in total footprint to total cost. The REPm92 performs best in each of these three categories, and would seem to be the best choice out of the models considered if total expenditures are considered the most important consideration.

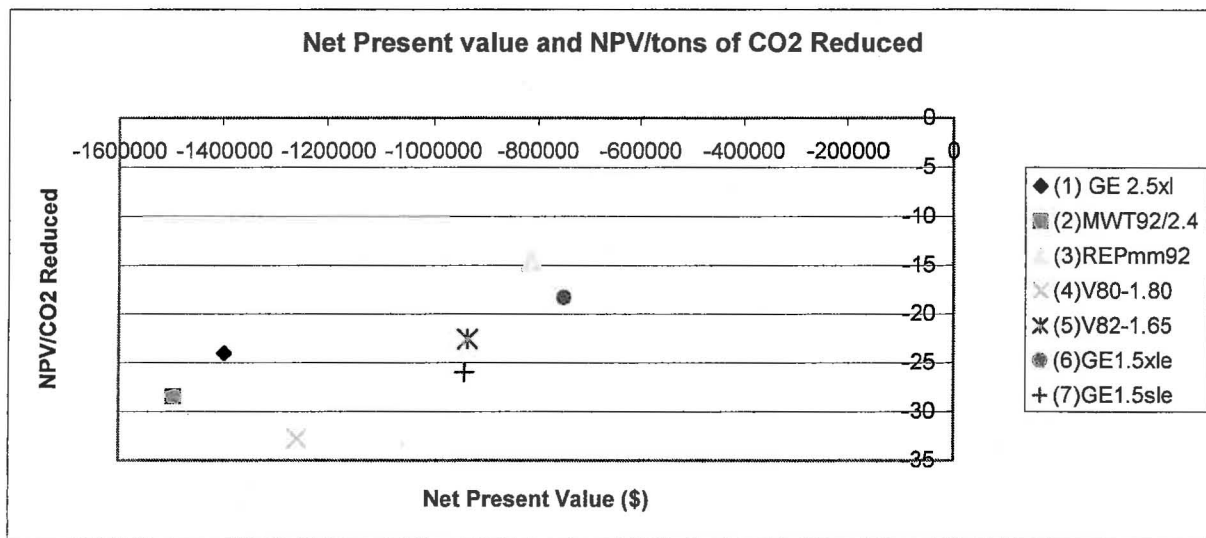
Table 4. Alternative Merits

| | NB/TC | price per ton CO ₂ reduced/TC | percentage footprint reduced/TC |
|------------------|----------|--|---------------------------------|
| (3) REPmm92 | 0.742203 | -4.63282E-06 | 2.3514E-06 |
| (6) GE 1.5xle | 0.69638 | -7.43414E-06 | 2.20711E-06 |

Alternatively the college may be more concerned with the relationship between the net present value of the project and the price per ton of CO₂ reduced. Figure 8 below illustrates the tradeoffs faced by the college with regards to Net Present Value and the cost per ton of CO₂

reduced. Generally utility to the college under these considerations would increase as points move up and to the right, however, the specific shape of the utility contour lines is uncertain. Clearly the REPmm92 and GE1.5xle are the most favorable options, and deciding between them will depend on the relative utility that the college derives from lower prices per unit of CO₂ offset and more favorable net present value.

Figure 8. Net Present Value and NPV/tons of CO₂ Reduced Frontier



Sensitivity Analysis

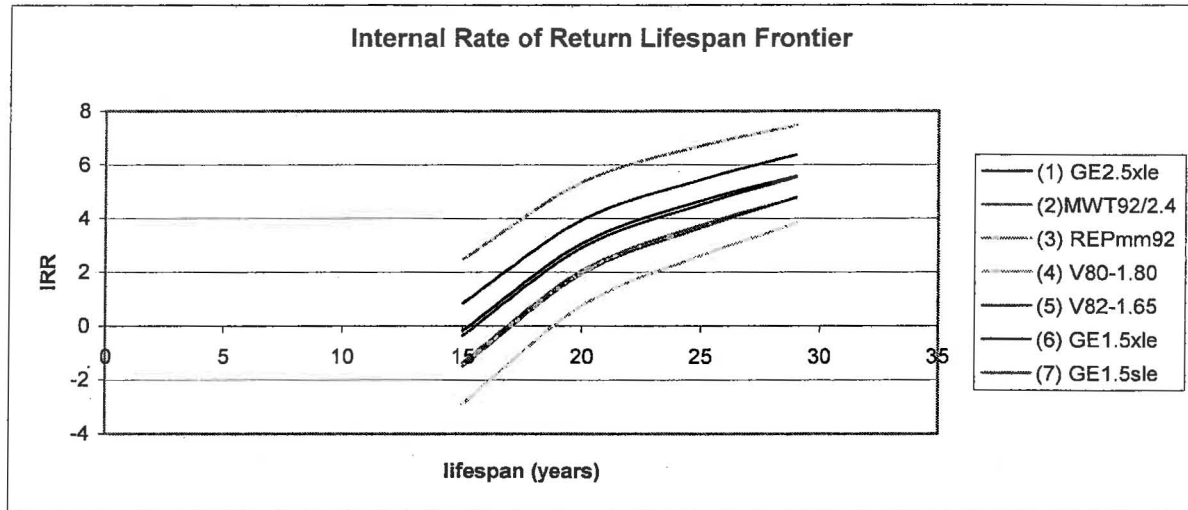
While some of the results above indicate that price and environmental conditions may make the adoption of wind power a favorable alternative to purchasing commercial offset credits, there is still a significant degree of uncertainty surrounding many of the assumed parameter values used in this analysis, as well as the method used for calculating net present value. As in any cost benefit analysis the assumptions regarding the discount rate as well as the project lifetime are critical. It should be intuitive that the results of the extrapolation of wind speeds from 50m to 80m have had a significant impact on the resulting assessment of the utility of a

wind turbine in this situation, as would any other changing environmental conditions that effect average wind speeds. The prices of the turbines as well as the cost of installation are not likely to be the same across all models. Finally, the highly conservative assumption that all capital costs would be paid in the first year is not entirely realistic if other financing options are available to the college.

The choice of the discount rate reflects the degree to which the college is concerned with current versus future expenditures and revenues. This choice may be particularly important if the funds that the college would have to expend immediately on capital cost put a strain on the rest of their yearly budget. In general, a lower discount rate will increase the relative utility of an option with higher initial costs and greater benefits over the long run, and reduce the relative utility of an option with lower initial costs and lower benefits over the long run, such as the REPmm92 and the GE1.5xle respectively. A similar effect should also be observed as the longevity horizon is expanded.

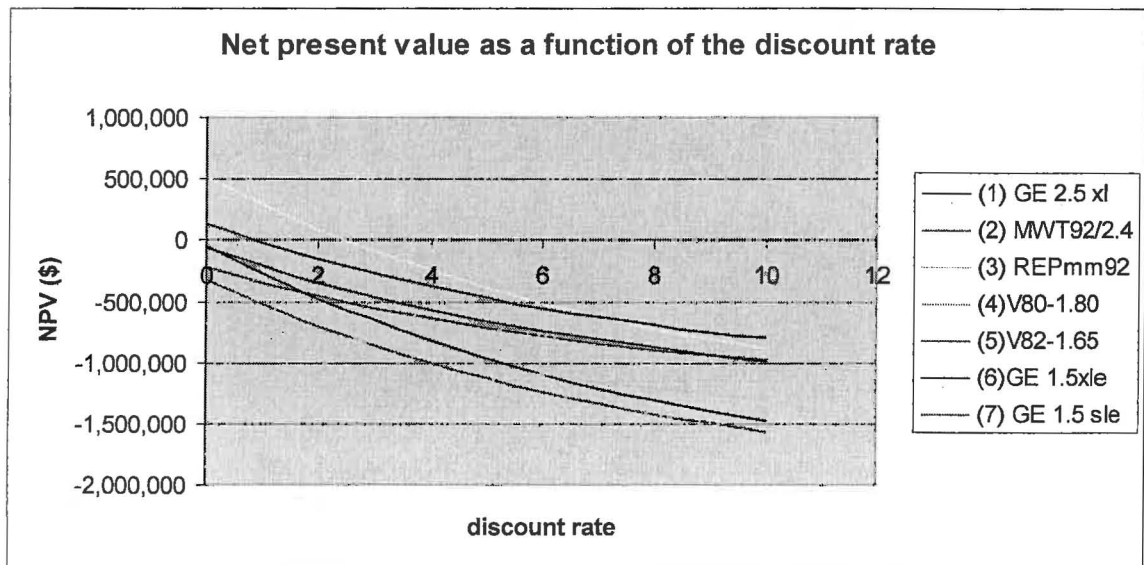
The Internal Rate of Return is the discount rate at which the net present value of an investment is zero. The figure below illustrates combinations of life spans and rates of return for each of the seven turbine models considered in this analysis. While no other investment decision (other than turbines) is expressly considered in this analysis, this figure would be particularly useful in comparing the value of a wind turbine to other investments through comparison of the internal rate of return and the rate of return on the alternative. This chart also may be read to infer the relative net present values of the different models: for a given lifespan, the turbine with the higher internal rate of return also has a higher net present value. Additional figures are listed that illustrate the sensitivity of the net present value and net present value per ton of CO₂ reduced as functions of both the discount rate and the lifespan.

Figure 9. Internal Rate of Return Lifespan Frontier



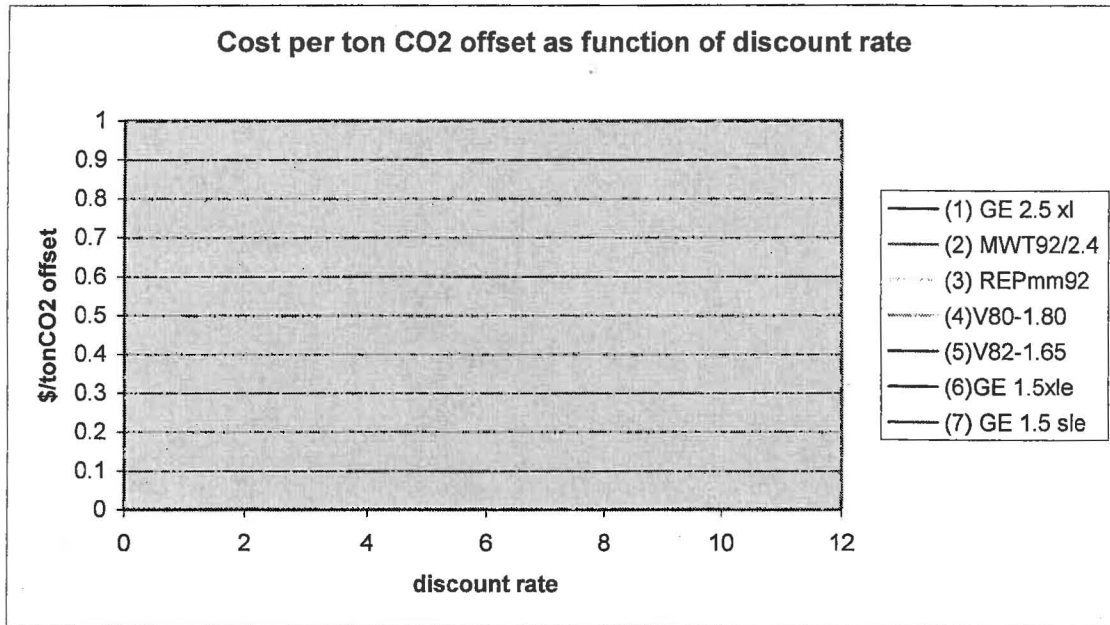
In Figure 10 below the net present value as a function of the discount rate is presented. It may be observed that as the discount rate increases the net present value of the GE1.5xle surpasses that of the REPmm92.

Figure 10. Net Present Value as a Function of the Discount Rate



It is also important to note that at a discount rate between two and three percent that the REPmm92 will actually have a positive net present value. In figure 11 the behavior of the cost per unit of CO2 reduced as a function of the discount rate is plotted.

Figure 11. Cost per Ton CO2 Offset as Function of Discount Rate



While zero values for the REPmm92 and GE1.5xle of course occur in the same locations as in the figure above the GE1.5xle does not over take the REPmm92 within the same horizon as above. Hence the choice of discount rate has a profound effect on ranking the relative merits of the turbines when net present value is of primary concern, but less so when the cost per ton of CO2 reduced is considered to be more important.

The modeling of the financing schedule used to this point has been intentionally conservative. While a complete treatment of all possible payment schemes is beyond the scope of this paper, the remainder of this section will focus on a much less conservative model in which all capital costs are averaged over the lifespan of the generator. In certain respects this

formulation creates a more realistic scenario, especially if, for example, the turbines were not bought outright but were instead leased from a private operator¹⁴. However, even in that scenario it is likely that some substantial upfront costs would still be transacted. Acknowledging the difficulties in approximating the most likely payment schedule, the model analyzed in this section attempts to describe the opposite end of the spectrum from the treatment used thus far. This section will discuss many of the features described above, as well as the sensitivity of its results to changes in average wind speeds and the turbines price per unit of capacity.

The averaging of capital costs over the lifespan of the turbine should increase the net present value of all turbines *ceteris paribus*. Indeed in Table 5 below it should be immediately noticeable that given the same parameter values used above (a five percent discount rate, and a fifteen year horizon) three models now have positive net present net benefits.

Table 5. Summary Statistics When Capital Costs Are Dispersed throughout the 15 Year Life Span with Discount Rates of Five Percent

| | (1) GE2.5xl | (2)MWT92/2.4 | (3)REPmm92 | (4)V80-1.80 | (5)V82-1.65 | (6)GE1.5xle | (7)GE1.5sle |
|------------------------------|-------------|--------------|-------------|-------------|-------------|-------------|-------------|
| Annual Statistics | 2500 | 2400 | 2000 | 1800 | 1650 | 1500 | 1500 |
| Output | 4339550 | 3918631 | 4158877 | 2868929 | 3093265 | 3052412 | 2706076 |
| Output/capacity | 1735.82 | 1632.762917 | 2079.4385 | 1593.8494 | 1874.7061 | 2034.94133 | 1804.05067 |
| tons CO2 offset | 3870.8786 | 3495.418852 | 3709.718284 | 2559.0847 | 2759.1924 | 2722.7515 | 2413.81979 |
| % of foot print offset | 7.7417572 | 6.990837704 | 7.419436568 | 5.1181693 | 5.5183848 | 5.44550301 | 4.82763958 |
| Sales Revenue | 200179 | 180971 | 191445 | 132749 | 142011 | 140426 | 124906 |
| 1 st 5 years rev. | 326025.95 | 294611.299 | 312052.433 | 215947.94 | 231715.69 | 228945.948 | 203382.204 |
| 6-15 th years rev | 282630.45 | 255424.989 | 270463.663 | 187258.65 | 200783.04 | 198421.828 | 176321.444 |
| Annual cost | 300000 | 290000 | 250000 | 230000 | 215000 | 200000 | 200000 |
| Discounted Values | | | | | | | |
| Total Revenue | 3121487 | 2820880 | 2987377 | 2067890 | 2217981 | 2191704 | 1947315 |
| Revenue/kwh capacity | 1248 | 1175 | 1493 | 1148 | 1344 | 1461 | 1298 |
| Total Cost | 3113897 | 3010110 | 2594914 | 2387321 | 2231626 | 2075931 | 2075931 |
| NPV | 7589 | -189220 | 392463 | -319430 | -13645 | 115772 | -128616 |
| NPV/ton of CO2 Reduced | \$0.13 | -3.61 | \$7.05 | -8.32 | -0.33 | \$2.83 | -3.55 |

¹⁴ In fact, such an arrangement may even yield additional benefits, as the College might recoup some of the tax deductible depreciation revenues earned by the private company.

All models produce offset prices that are well below those available from most reputable commercial offset vendors. Whereas before the top three turbines (in order) in the categories of net present value, price per ton of CO₂ reduced, output per capacity, and revenue per capacity were the REPmm92, the GE1.5xle and the V82-1.65, now the GE2.5xl has a better net present value and price per ton of CO₂ reduced than the V82-1.65, and maintains the highest percentage of the college's footprint reduced. Hence it would seem that under this payment schedule, the GE2.5xle would be the best option if the college is relatively unconcerned with its total expenditures, and is primarily concerned with total reductions and a nonnegative net present value.

Wind speeds and the turbine price per kwh should also be expected to influence the net revenue and the cost per ton of offset CO₂ emissions. If the revenue of a given turbine is a function of wind speed, then net present value will equal zero when (the discounted value of) the following is true,

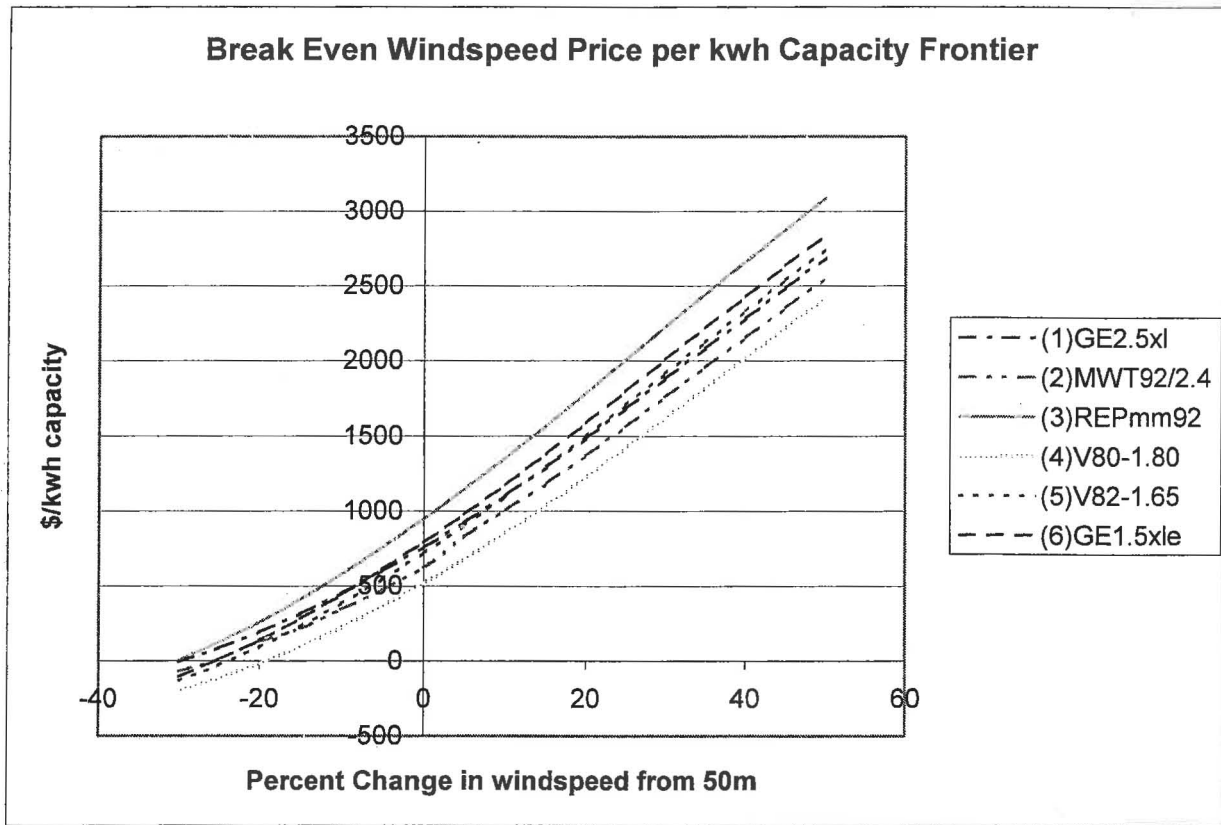
$$(Eq. 4) \quad P_k * K + L * M = L * R(w)$$

-or-

$$(Eq. 5) \quad P_k = L[R(w) - M]/K$$

Where P_k is the price of a turbine (including installation) per kilowatt of capacity (K), L is the lifetime of the project in years, M is the annual operation and maintenance cost, and $R(w)$ is the annual revenue of a turbine (including subsidies) as a function of wind speeds. Hence, it is possible to graph the price per kilowatt hour of capacity necessary to achieve zero net annual cost as a function of the percent difference in wind speed from the readings taken at 50m as in the figure below (for the purpose of simplicity the GE1.5sle has been omitted).

Figure 12.



Reading this graph, one can determine what the maximum cost per kilowatt hour of capacity must be for a given turbine to have a net present value of zero for wind speeds of a certain percentage different from those recorded at 50m. A parallel interpretation of this chart is that each point on the line also represents a point where the price of offsetting a ton of CO₂ is zero. At any given point, zero profits (annual revenue minus annual cost) will be earned. Also at any given point higher average wind speeds or lower cost per unit of capacity will lead to positive profits, while lower average wind speeds or higher price per unit of capacity will lead to negative profits.

Notice that at a twenty percent increase both the REPmm92 and the GE1.5xle have positive net benefits at a cost of \$1500/kwh, and that at that cost wind speeds need only be between 14 and 16 percent higher than recorded at 50m for the REPmm92 to have zero net

present value. It is also interesting to note that for almost the complete domain the ranking of the five models is consistent except for at the very unlikely low speeds below 18 percent less than 50m, and for the GE2.5xl and V82-1.65 near ten percent increased speed. This may seem counterintuitive, as one might expect that as wind speeds increase the larger turbines would become more efficient, i.e., that they could bear a higher cost per unit of capacity than smaller turbines. However, the opposite trend is instead observed. As wind speeds increase both the GE1.5xle and the V82-1.65 move further apart from the MWT92/2.4 and the V80-1.80. This may be attributable to the models specific power curves, the cyclical patterns of wind and prices, or some combination of these factors.

As noted earlier, the unit of price per kwh of capacity has some useful interpretations that are well illustrated in this graph. Improvements in technology may be measured as a decrease in price per unit of capacity. This chart allows turbines with different costs per unit of capacity to be compared easily. Wind turbine efficiencies have consistently improved with time (although not at a constant rate), so the vertical axis may also be thought of as a negative time axis. As time moves forward, *ceteris paribus*, lower wind speeds are required for any turbine to be profitable at a given price. Alternatively, if global climate change or other long term weather patterns result in a consistent pattern of changing average wind speeds, then the horizontal axis can be read as a time axis in which ever direction that trend heads (i.e., if climate change results in milder weather, then time would read to the left on the horizontal axis, and vice versa). While it is unclear as to the rates at which time moves either efficiency or weather patterns, this interpretation may be very useful in determining the timing of a wind turbine investment decision.

Discussion

The results as outlined above have demonstrated interesting aspects of the primary research questions explored by this study. It should be clear that the relative weight applied by the college to total costs, net present value, and cost per unit of carbon dioxide offset will ultimately be critical in determining their decision. Also critical will be the way in which the cost structure is scheduled, which will reflect also the college's willingness to discount future benefits and costs. The remainder of this section will discuss a few additional interpretations of the results as related to the motivation of this paper, as well as outline avenues to expanding this research.

One of the important contributions of this paper is the inclusion of spot market prices in evaluating the viability of wind power in Oberlin. The degree to which wind speeds and prices are correlated was analyzed in the data summary, which indicated that there was not a clear relationship between wind speeds and prices. As mentioned above, this nonlinearity is due to factors such as the paths of turbine power curves, and the distribution of wind speeds and prices. Table 6 contains the correlation coefficients between electricity generation and spot prices for each of the turbine models considered in this study.

Table 6. Correlation between hourly Output and Prices.

| | | | | | | |
|------------|--------------|-------------|-------------|-------------|-------------|-------------|
| (1)GE2.5xl | (2)MWT92/2.4 | (3)REPmm92 | (4)V80-1.80 | (5)V82-1.65 | (6)GE1.5xle | (7)GE1.5sle |
| 0.0454234 | 0.045638603 | 0.044765808 | 0.0470931 | 0.03958942 | 0.0448131 | 0.0458098 |

During the majority of the year wind speeds and prices are negatively correlated while each of the turbines demonstrates positive (although small) correlation between output and prices. However, the relationship between the relative correlations of output and prices amongst the turbines does not reflect the relative utilities of the turbines in the cost benefit analysis presented

here. For example, the GE1.5sle has a higher correlation than the GE1.5xle, but has performed worse in every aspect of the cost benefit analysis. Thus it would seem that while using spot market prices can be useful in terms of accurately estimating the utility of various wind turbines (doing so here has resulted in positive net benefits under similar constraints as those used by Scofield et al. (2007) which did not find positive net benefits), it may be less important when ranking the relative utilities of similar turbines.

Although a real options approach has not been implemented here such an application could provide further insight into this problem. A real options approach to cost benefit analysis seeks to include any strategic values of an investment when determining the optimal timing of an investment decision. These costs or benefits can, for example, include costs of delay due to the necessity of an intermittent generation source, improvements in technology, changes in environmental conditions, or new regulations that effect costs or price. Real options emphasizes that if an expected net benefits calculation depends on risky or uncertain parameters that in some cases result in negative values, there may be a strategic value to waiting until the risk or uncertainty is resolved until making the investment decision. In many cases even if a project has a positive net present value, it may still be optimal to wait until some uncertainty or risk has been resolved. This may be of particular gravity for investment decisions that are largely irreversible and have high sunk costs such as wind turbines¹⁵.

Applying real options to the situation considered in this paper might necessitate characterizing the uncertainties of developments in turbine technology, wind speeds, the prices and values of commercial carbon offsets, the feasibility of other similar alternatives to investment in wind turbines (such as solar or bio-mass), and long term energy prices among

¹⁵ While it may seem that turbines actually could have a resale value (especially as compared to other forms of installed electricity generators) the current lack of a market for used turbines might result in prohibitive transaction costs.

others. The cost of delay in this case would include any expenses on commercial offsets or other temporary emissions reductions efforts, as well as any net revenues that a turbine with positive net present value might generate. As the costs incurred in erecting a wind turbine are largely unrecoverable, it would be likely that if significant uncertainty exists in the parameters mentioned above then the results of a real options analysis could have a significant impact on the optimal decision in this situation

Depending on the characterizations of the risk and uncertainty in any of these parameters a real options analysis could change the results presented here in a variety of ways. If, for example, Oberlin expected the United States to ratify the Kyoto Protocol or some other similar agreement at some point in the next 15 years, and that this would result in increased demand for both renewable energy and carbon offsets, then depending on the current cost of carbon offsets it may be optimal to delay investment in a wind turbine even if that turbine has a positive net present value. Alternatively if new marketing research indicated that the degree to which applications to a specific college and the date at which that institution achieved carbon neutrality are correlated was likely to increase at some point in the near future then a real options analysis might indicate that it would be optimal to invest in wind turbines that do not necessarily have a positive net present value.

Conclusion

This paper has attempted to present information and analysis to inform the decision of Oberlin College as it considers wind turbines as an alternative to commercial carbon offsets, as well as to illustrate various aspects of determining the value of wind turbines that have been lacking in the literature on this topic. Using a standard cost benefit analysis and analyzing the sensitivity of various assumed parameters the results suggest that several of the turbines

considered here will produce offsets in carbon dioxide emissions at a cost comparable to commercially available offsets, and that as certain parameters are relaxed may also result in positive net present value.

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